BEST AVAILABLE CONTROL TECHNOLOGY EVALUATION FOR OXIDES OF NITROGEN

for

INTERMOUNTAIN POWER SERVICE CORPORATION
INTERMOUNTAIN POWER PLANT (DELTA, UTAH)
REVAMP PROJECT

Prepared for:

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TABLE OF CONTENTS

TABLES

ACRONYMS

BACT	Best Available Control Technology
CO	Carbon Monoxide
CRF	Capital Recovery Factor
DAQ	State of Utah Division of Air Quality
EPA	United States Environmental Protection Agency
F	Fahrenheit
FGR	Flue Gas Recirculation
HP	High Pressure
IGS	Intermountain Generating Station
IPSC	Intermountain Power Service Corp
kW	Kilowatt
LADWP	Los Angeles Department of Water & Power
LNB	Low NOx Burner
LOI	Loss On Ignition
MMBtu	Million British Thermal Units
MW	Megawatt
NOI	Notice of Intent
NOx	Nitrogen Oxides
OFA	Overfire Air
O&M	Operating & Maintenance
ppm	parts per million
%	Percent
psi	pounds per square inch
SCR	Selective Catalytic Reduction
SIC	Standard Industrial Classification
SNCR	Selective Non-catalytic Reduction
SO_2	Sulfur Dioxide
VOC	Volatile Organic Compounds

1.0 INTRODUCTION

Intermountain Power Services Corporation (IPSC) operates a two-unit coal-fired power plant, Intermountain Generating Station (IGS), in Delta, Utah. The Los Angeles Department of Water and Power (LADWP) is the "Operating Agent" of the facility and currently receives a significant amount of power generated by this power plant. IPSC proposes to revamp the power plant and increase power generation capacity by implementing a series of changes at the plant. IPSC prepared and submitted a Notice of Intent (NOI) on April 4, 2001 to the State of Utah Division of Air Quality (DAQ). The NOI is provided in Attachment 1. The DAQ has requested IPSC to prepare a limited BACT analysis for oxides of nitrogen (NOx), considering certain specific NOx control technologies.

LADWP retained Parsons Engineering Science (Parsons ES) to perform the BACT evaluation for the IPSC Power Plant. Parsons ES has evaluated the NOx control technology options as specified by DAQ to reduce NOx emissions. This report presents the results of the BACT evaluation study.

2.0 PROJECT DESCRIPTION

The IGS is a fossil fuel-fired steam-electric generating station that primarily uses coal as fuel for producing steam to generate electricity (SIC Code 4911). The IGS fires both bituminous and subbituminous coals. Fuel oil and used oil are also combusted for light off and energy recovery.

The IGS is a two-unit facility currently operating at a rated capacity of 875 megawatts (MW) per unit (gross). The project covered by this analysis will increase operating capacity to approximately 950 MW per unit. Approximately 5.6 million tons of coal and 600,000 gallons of oil (fuel oil and used oil) will be used each year at the new rate of production. Boiler operating capacity will be rated at 6.9 million pounds per hour of steam flow at 2,975 psi.

Each unit is dry bottom wall-fired. Dual register low-NOx burners were installed during the original construction of each unit around 1986-87. Table 1 shows the typical average fuel characteristics of the coal currently used at the power plant.

IGS has in place bulk handling equipment for unloading, transfer, storage, preparation, and delivery of solid and liquid fuel to the boilers. No changes in this equipment are proposed. In addition, no changes in the usage of other raw materials or bulk chemicals are planned.

IPSC plans to enhance steam flow characteristics through the high pressure (HP) section of each turbine used to generate electricity. This would involve replacing the HP blade section with a modified design that would improve performance and reliability.

TABLE 1
TYPICAL IPSC COAL
PHYSICAL AND CHEMICAL CHARACTERISTICS

Parameter	Actual Average
Heat Value	11,850 btu/lb
Moisture	8.5 %
Ash	9.2 %
Sulfur	0.52 %
Sodium	4 %
Grindability	46 HGI
%H2O	6.63 %
%C	67.82 %
%H	4.86 %
%N	1.31 %
%S	0.52 %
%O	10.08 %
Antimony	3.1 ppm
Arsenic	12 ppm
Barium	113 ppm
Beryllium	0.38 ppm
Cadmium	0.66 ppm
Chromium	24 ppm
Cobalt	2.9 ppm
Copper	7.8 ppm
Hydrogen Chloride	299 ppm
Hydrogen Fluoride	63 ppm
Lead	7.1 ppm
Manganese	9.9 ppm
Mercury	0.061 ppm
Nickel	4.7 ppm
Selenium	2.4 ppm
Vanadium	5.6 ppm
Zinc	7.4 ppm
Silicon Dioxide	65.2 %
Aluminum Oxide	17.5 %
Titanium Dioxide	0.8 %
Iron Oxide	3.3 %
Calcium Oxide	7.1 %
Magnesium Oxide	2.9 %
Potassium Oxide	1.5 %
Sodium Oxide	0.9 %
Phosphorus Pentoxide	0.2 %
Silica Equivalent Value	86.4 %
Base:Acid Ratio	0.15
Fusion Temperature (T250)	2900+ F

NOTE:
Data provided here are estimates only, based on available industry-wide information combined with specific analyses. These are not limits, but arithmetic means bounded by wide ranges of concentrations that are dependent on fuel source and type. Solid fuels naturally have wide variability in characteristics. This fuel information is in no way intended to represent binding fuel parameters.

Combined improvements to other areas of the plant would increase plant-generating capacity. These modifications would consist of "de-bottlenecking" critical points that presently prevent the full use of present equipment. Other changes are needed for reliability, performance and/or routine maintenance purposes.

The existing pollution control devices at the power plant include dual register low-NOx burners, baghouse type fabric filters for particulate removal, and flue gas desulfurization scrubbers. The existing low-NOx burners provide a nominal 60% reduction in potential combustion NOx generation. The baghouse filters operate at nominal 99.95% efficiency. The wet sulfur dioxide (SO_2) scrubbers operate at nominal 90% efficiency. Control equipment for handling and transfer of solid material includes dust collection filters.

The proposed project includes modifications to the flue gas flow through scrubber modules to enhance SO_2 removal rates. Also, the project proposes replacing the existing dual register low-NOx burners with new technology low-NOx burners.

3.0 REGULATORY REQUIREMENTS

IPSC has completed and filed a Notice of Intent (NOI) with the DAQ for the proposed IGS project. Rule 307-401-6 provides the conditions for issuing an approval order in response to a NOI. R307-401-6(1) requires the source to apply Best Available Control Technology. Rule 307-413 lists available exemptions from the NOI and approval order requirements. Exemptions exist for de minimis Emissions, Flexibility Changes, Replacement-in-Kind Equipment and Reduction of Air Contaminants. However, these exemptions do not appear to apply to the IGS project as currently defined.

Utah R307-101-2 provides the definition of BACT as follows:

"Best Available Control Technology (BACT) means an emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree or reduction of each pollutant subject to regulation under the Clean Air Act and/or the Utah Air Conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental and economic impacts and other costs, determines is achievable for such installation through application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall applications of BACT result in emissions of any pollutants, which will exceed the emissions allowed by Section 111 or 112 of the Clean Air Act."

In addition, R307-410-6 requires that permit approvals be granted only if the degree of pollution control is at least as good as BACT as defined above, except as otherwise provided in the rules. The federal Clean Air Act requires that BACT be installed on new major sources and major modifications of existing sources in attainment or PSD areas. There is no federal requirement for BACT on minor sources or minor modifications; therefore, the state minor source BACT requirement is more stringent than the federal requirement. It would appear that the requirement is contrary to Utah Code Ann. 19-2-106; however, IPSC provisionally feels that a BACT analysis for this particular project is not unreasonable. No other provisions in the State rules provide relief from BACT for minor modifications. Therefore, it appears that BACT must be applied.

Typically BACT is determined following the United States Environmental Protection Agency (EPA) "top-down" methodology in which all applicable technologies are considered and first evaluated on technological feasibility considerations for the specific application. Those that are not deemed to be technologically feasible are set aside. The remaining technologies are ranked in descending order starting with the highest possible control efficiency. An economic analysis is conducted for each of these with the results (cost-effectiveness) being reported in dollars per ton of emissions removed. The technology that has the highest cost-effectiveness meeting a specified regulatory threshold is then typically selected as BACT provided other considerations such as energy and other environmental impacts are deemed acceptable.

The DAQ specifies that the following criteria be considered in determining BACT (Reference 1):

1. Energy Impacts – especially focusing on any significant or unusual direct energy penalties that may be required on either an absolute or on an incremental basis.
2. Environmental Impacts – this should focus on non-air quality impacts (such as solid or hazardous waste generation or the discharge of polluted water) that may result due to the application of BACT; this analysis should also consider the generation of any toxic or hazardous air contaminants not regulated under the Clean Air Act.
3. Economic Impacts and Cost Calculations – in this analysis the costs of controls are quantified considering capital as well as operating costs.
4. Other Considerations – this allows the consideration of factors, not necessarily economic that may affect the selection of BACT including incremental cost-effectiveness, ability to control more than one pollutant, etc.

Based on prior discussions, the DAQ has indicated to IPSC that the BACT evaluation should be performed for only NOx emissions. Furthermore, rather than a full top-down analysis, IPSC has requested the consideration of five specific technologies for the BACT analysis. Finally, DAQ has indicated that the cost-effectiveness threshold for reasonable BACT for this minor modification is about $2,000 per ton of NOx removed. DAQ policy otherwise considers $5,000 per ton reasonable for major modifications.

4.0 BACT ANALYSIS

Parsons ES has evaluated the NOx BACT technology alternatives selected by IPSC and DAQ. Technologies considered include (1) ultra Low-NOx burners, (2) ultra Low-NOx burners with overfire air, (3) Mobotec Rotating Overfire Air (ROFA), (4) selective non-catalytic reduction (SNCR), and (5) selective catalytic reduction (SCR). Flue Gas Recirculation (FGR) was also initially considered as an applicable NOx control technology. While FGR is used frequently on gas-fired power plants, it is not considered a viable NOx control technology for coal-fired power plants. In fact, the EPA does not include FGR as a NOx control option for coal-fired power plants in its most recent edition of AP-42.

Each of the technologies selected for evaluation is briefly discussed below:

4.1 Ultra Low-NOx Burners – New generation low-NOx burners being considered will be similar to burners manufactured by Babcock and Wilcox (Model DRB-4Z), which are three stage burners. Additional details of these burners are presented in Reference 2. These burners were recently developed and are now in commercial use (Reference 2). Parsons estimates these burners can provide an additional 15% reduction in the NOx emissions at each IPSC unit. The estimated capital cost is approximately $5.2/kW. Fixed O&M costs are in the range of $0.035/kW-yr and variable O&M costs are negligible. These generic cost data are taken from vendor burner quotes and IPSC operating cost experience (Reference 8).

BACT Criteria Summary for Ultra Low-NOx Burners:

- Energy Impacts: Negligible compared to dual register Low NOx burners
- Environmental Impacts: A potential increase in CO emissions is likely along with the reduction in NOx emissions. Additional fuel use associated with the project will also result in a proportional increase in the emissions of CO, VOC and other toxic compound emissions
- Economic Impacts: Replacement costs
- Other Considerations: None

4.2 Ultra Low-NOx Burners with Overfire Air – When combined with overfire air (OFA), an even greater NOx reduction can be attained with ultra Low NOx burners (around 50%), possibly achieving 0.17 lb/MMBtu NOx emissions at full load. No significant energy penalties would result beyond new fan requirements. However, CO emissions may increase as NOx emissions are reduced to low levels. No data are available on the impacts on other air pollutant emissions such as that for VOCs or other air toxics – however, these are expected to mirror the increase in CO emissions. The estimated capital cost of these burners with overfire air is $11.6/kW. Fixed O&M costs are in the range of $0.048/kW-yr and variable O&M costs are in the range of $0.13/MWh. The capital costs were derived from vendor estimates provided by IPSC (Reference 8). Operating and maintenance costs were derived from IPSC experience with Low NOx burners and the costs associated with the fan (Reference 8). In addition, the use of ultra Low-NOx burners with overfire air can increase the Loss on Ignition (LOI). This increase in LOI may render the ash unsuitable for sale and may require disposal. Costs have been included from loss of revenue for the reduced ash sales and costs for subsequent ash disposal.

BACT Criteria Summary for Ultra Low-NOx Burners with overfire air:

- Energy Impacts: Additional fan use, lower efficiency due to potentially increased LOI
- Environmental Impacts: Additional ash disposal; higher CO, VOC and air toxics emissions
- Economic Impacts: Loss of ash sales; installation of new fans; higher fan cost, retrofit ductwork
- Other Considerations: None

4.3 MOBOTEC Rotating Overfire Air (ROFA) – This technology is primarily overfire air. However, computer modeling is performed on the combustion chamber to properly design the system. In ROFA, tangentially placed secondary air ports on opposite sides of the furnace rotate the volume of air and fuel creating extensive mixing and a cyclonic effect. Through the use of a booster fan the secondary air is introduced into the furnace at about 170 miles per hour creating a cyclone. This cyclonic rotation results in an excellent mixture of air and fuel providing a very efficient combustion process. The tangentially placed air ports are usually installed at a higher level in the furnace than the conventional over fire air ports.

The manufacturer claims that ROFA can provide a 50% reduction in NOx emissions – although this is likely from a base on uncontrolled NOx emissions. Since the IPSC units already have existing low-NOx burners, the extent of further NOx reductions have to be evaluated on a site-specific basis. Likely emissions reductions are thought to be below 50%. ROFA has been installed commercially at a few power plants. At the Carolina Power and Light Cape Fear Plant, ROFA has reduced NOx emissions from 0.60 lbs/MMBtu to 0.27 lbs/MMBtu while operating at 154 MW. This is the largest ROFA installation. Scaling this technology to the size of the IPSC units (i.e., to 950 MW each) is non-trivial since proper modeling and placement of the secondary air ports and resultant mixing is essential to achieve the claimed NOx reductions. Further, ROFA is designed for application to tangentially-fired or cyclonic boilers. ROFA used in wall-fired boilers may actually increase NOx emissions (Reference 8). As a result, this technology is still considered untested at units of this size and type, and, therefore, was eliminated from further consideration at this time. No cost estimates were developed for this technology.

4.4 Selective Non-Catalytic Reduction – SNCR uses ammonia (or a similar reducing agent such as urea) injection directly into the combustion chamber at a location of specified temperatures. The ammonia reacts with NOx directly in the gas phase to reduce NOx emissions. SNCR could provide a maximum of around 40% reduction in NOx emissions from current levels at IPSC. SNCR has been used and is considered a proven technology for coal-fired power plants, especially for base-loaded units such as IPSC. Minimal energy penalties are associated with SNCR, primarily relating to operating the ammonia injection system. SNCR does result in emissions of excess ammonia called ammonia slip. The ammonia slip is ammonia that has not reacted with the NOx. However, ammonia slip is a SNCR design parameter that can be set at a specific level, typically less than 5 ppm. The approximate installed capital cost for SNCR is $9-12/kW. Fixed O&M costs are estimated to be $0.11/kW-y and variable O&M costs are $0.356/MWh and can be higher depending on the cost of ammonia. Costs were based on information provided by IPSC (Reference 8).

BACT Criteria Summary for Selective Non-Catalytic Reduction:

- Energy Impacts: Negligible
- Environmental Impacts: Projected NOx reduction less than LNB with OFA. Additional SNCR results in ammonia emissions to the atmosphere from ammonia slip
- Economic Impacts: Annualized cost greater than LNB with OFA
- Other Considerations: Safety considerations associated with chemical transportation, storage, and handling

4.4 Selective Catalytic Reduction – SCR uses ammonia or some other reducing agent (but mostly ammonia) in the presence of a catalyst (located in a region of specified flue gas temperatures, typically 550°F to 900°F) to reduce NOx emissions. A 70-90% reduction in NOx is achievable with SCR, depending on the level of NOx present. A 75% NOx reduction may be possible at large coal-fired power plants such as IPSC. Like SNCR, SCR results in emissions of excess ammonia associated with the ammonia slip. SCR has now been used for several years on coal-fired power plants in Europe (Germany, Austria, Denmark, etc.), Japan, and in the US (since 1995). Several different SCR configurations have been used and validated (Refs 4, 5) including high-dust (where the catalyst is placed upstream of the air preheater and the particulate controls); low-dust (catalyst after the particulate controls), etc.

Designs can accommodate a wide variety of coals (including specific ash, moisture, sulfur, calcium and arsenic contents) and can achieve specified levels of ammonia slip using either anhydrous or aqueous ammonia. Currently, over 300 applications of SCR are planned at US power plants.

Indeed, current SCR implementation is limited from a schedule standpoint due to the large backlog of orders resulting in 52 weeks or more for delivery. However, discussions with SCR vendors have indicated that no SCR units are currently installed on power plants that combust coal with characteristics similar to the coal burned at IPSC (i.e., Utah coals). Thus, at this time, SCR is not considered a demonstrated technology.

SCRs do have potential energy penalties as they incur additional pressure drop and require additional power to operate. The approximate installed cost for SCR is $79/kW. Costs vary widely depending on the coal characteristics (since that affects the nature and amount of catalyst to be used), whether it is a new installation or a retrofit and the configuration of the control train. Fixed O&M costs are roughly $1.84/kW-yr for normal life installations and variable O&M costs are around $0.287/MWh. Costs were based on vendor data and information provided by IPSC (Reference 8).

BACT Criteria Summary for Selective Catalytic Reduction:

- Energy Impacts: Increased fan use to overcome pressure drop
- Environmental Impacts: Ammonia slip; waste disposal (spent catalyst)
- Economic Impacts: Estimated capital cost for SCR is 9.4 times the estimated capital cost of the entire IPSC improvement project
- Other Considerations: Long delivery times, incremental costs, currently not commercially demonstrated with Utah coal

IPSC's NOx emissions averaged 25,144 tons/year for the years 1999 and 2000. The total emissions are divided equally between the two identical units when averaged over two years. The proposed project without any NOx control would increase NOx by 2,816 tons/year for total NOx emissions of 27,960 tons/yr. A decrease in NOx emissions of 2,777 tons/year from the above value would result in a minor modification, which is defined as "an increase in NOx emissions to less than 40 tons/year."

Table 2 summarizes the estimated plant wide (i.e., both units) emissions reduction for each technology, the installed cost and the estimated cost per ton of NOx controlled. Details of the cost calculation are shown in Table 3. Incremental costs to meet minor modifications are also analyzed and presented. Table 4 provides the capital cost comparison for the base project and the base project with each NOx control technology studied.

TABLE 2
SUMMARY OF NOx CONTROL TECHNOLOGIES
FOR THE IPSC POWER PLANT
TWO 950 MW UNITS

TECHNOLOGY	ABSOLUTE EMISSION REDUCTION (TONS/YEAR)	INCREMENTAL EMISSION REDUCTION FOR MINOR MODIFICATION (TONS/YR)	INSTALLED COST (MM$)	ABSOLUTE COST EFFECTIVENESS ($/TON REMOVED) [2]	INCREMENTAL COSTS ($/TON REMOVED) [4]
Ultra Low NOx Burners	4,194	2,777	9.9	254	383
Ultra Low NOx Burners with Overfire Air	13,980	2,777	22.0	298	1,502
Rotating Overfire Air [1]	-		-	-	-
Selective Non Catalytic Reduction	11,184	2,777	18.4	634	1,192
Selective Catalytic Reduction	19,572	2,777	150.0	1,140 [3]	7,281

Notes:

[1] Not technologically demonstrated for this size and type of unit.
[2] See Table 3 for details.
[3] No operating installation on power plants that burn coal having the characteristics of the coal combusted at IPSC.
[4] Incremental Costs ($/ton) represent costs to only reach the minimum required NOx reduction of 2,777 tons in order to keep the proposed project a minor modification.

TABLE 3
COST CALCULATION DETAILS

Absolute Cost Evaluation

Technology	Pre-control NOx Emissions (tons/yr)	Absolute Emission Factor (% reduction)	Absolute Emission Reduction (tons/yr)	Capital Costs (MM$)	Unit Fixed O&M ($/kWh)	Total Fixed O&M (MM$/yr)	Unit Variable O&M ($/MWh)	Total Variable O&M (MM$/yr)	Life (yrs)	Interest Rate (%)	CRF	Absolute Annualized Cost (MM$/yr)	Absolute Cost Effectiveness ($/ton removed)
LNB	27,960	15	4,194	9.9	0.035	0.056	0.000	0	25	9	0.1018	1.064	254
LNB w/OFA	27,960	50	13,980	22.0	0.048	0.078	0.131	1.853	25	9	0.1018	4.170	298
SNCR	27,960	40	11,184	18.4	0.111	0.179	0.356	5.042	25	9	0.1018	7.094	634
SCR	27,960	70	19,572	150.0	1.837	2.967	0.287	4.066	25	9	0.1018	22.304	1,140

Incremental Cost Evaluation

Technology	Pre-control NOx Emissions (tons/yr)	Minor Modification Emissions Reduction (tons/yr)	Capital Costs (MM$)	Unit Fixed O&M ($/kWh)	Total Fixed O&M (MM$/yr)	Unit Variable O&M ($/MWh)	Total Variable O&M (MM$/yr)	Life (yrs)	Interest Rate (%)	CRF	Incremental Annualized Cost (MM$/yr)	Incremental Cost for Minor Modification ($/ton removed)
LNB	27,960	2,777	9.9	0.035	0.056	0	0	25	9	0.1018	1.064	383
LNB w/OFA	27,960	2,777	22	0.048	0.078	0.131	1.853	25	9	0.1018	4.170	1,502
SNCR	27,960	2,777	18.4	0.111	0.179	0.089	1.259	25	9	0.1018	3.311	1,192
SCR	27,960	2,777	150	1.837	2.967	0.14	1.981	25	9	0.1018	20.219	7,281

Notes:
[1] Costs shown are for the total plant capacity of 1,900 MW.
[2] Estimated costs are vendor specific with adjustments based on EPA's CUE Cost Workbook provided by IPSC (Reference 8).
[3] Capital Cost adjustments are from direct vendor information provided by IPSC (Reference 8).

TABLE 4
CAPITAL COST COMPARISON

Technology	Technology Capital Cost (MM$)	Base Project (MM$)	Total Cost (MM$)	Cost Ratio (Total/Base)
LNB	9.9	16.09	25.99	1.62
LNB w/OFA	22.0	16.09	38.09	2.37
SNCR	18.4	16.09	34.49	2.14
SCR	150.0	16.09	166.09	10.32

5.0 CONCLUSION

Based on the regulatory requirements pertaining to NOx BACT, the various considerations that must be taken into account in the determination of BACT, and the reasonable cost-effectiveness thresholds used by DAQ, BACT for IPSC is discussed below:

Selective Catalytic Reduction
Given: 1) Extreme costs involved for adding SCR to keep this project a minor modification, 2) excessive costs when compared to project cost (see Table 4) for absolute NOx reductions, 3) additional ammonia emissions to the environment, 4) delivery times in excess of 52 weeks, and 5) likely technical difficulties to be overcome when applying SCR with Utah coal since there are no operating installations.
Determination: SCR as a retrofit NOx control technology is rejected.

Selective Non-Catalytic Reduction
Given: 1) Prohibitive costs (annualized) for both incremental and absolute NOx reductions, 2) NOx reductions less than LNB with OFA, and 3) additional ammonia emissions to the environment.
Determination: SNCR as a retrofit NOx control technology is rejected.

Rotating Over Fire Air
Given: ROFA is technically unproven for this size and type of unit.
Determination: ROFA as a retrofit NOx control technology is rejected.

Ultra Low-NOx Burners with Overfire Air
Given: 1) Increase in CO emissions to the environment, 2) increased loss on ignition (LOI) resulting in loss of ash sales revenue, 3) increase in land disposal of combustion wastes, and 4) high incremental cost for minor mod NOx removal.
Determination: LNB w/OFA as a retrofit NOx control technology is rejected.

Ultra Low-NOx Burners

Given: 1) Ease of replacement, 2) low cost of installation and operation, 3) a potential minor increase in CO emissions, and 4) moderate incremental cost for minor modification NOx removal.

Determination: Ultra low NOx burners as a replacement-in-kind NOx control technology is recommended as BACT for this project.

6.0 REFERENCES

1. Best Available Control Technology, policy guidelines from Utah DAQ, DAQ Website 2001.
2. First Commercial Application of DRB-4Z Ultra-Low NOx Coal Fired Burner, Bryk, S. A., et al, BR-1710, presented at Power-Gen International 2000.
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4. Performance of SCR on Coal-Fired Steam generating Units, Acid Rain Program, EPA 1997.
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6. Proceedings from the FOMIS (Scientech) 1999 Winter Conference, "SNCR, SCR, And Gas Reburning - Technical Issues and Tradeoffs," James E. Staudt, Andover Technology Partners, Inc., 112 Tucker Farm Road, North Andover, MA 01845
7. "Status Report on NOx Control Technology & Cost Effectiveness for Utility Boilers," Northeast States Coordinating Air Use Management Committee, June 1998. Prepared by James E. Staudt, Andover Technology Partners, Inc., 112 Tucker Farm Road, North Andover, MA 01845
8. IPSC, Transmittals from Rand Crafts to P. C. Tranquill consisting of data and information from Reaction Engineering of Salt Lake City, Utah; B&W of Barberton, Ohio; Cormetech, Inc. of Durham, North Carolina and Advanced Burner Technologies of Morgan, Pennsylvania, dated May 21, 2001 and May 22, 2001.

Attachment 1

Copy of NOI dated April 4, 2001